DISCUSSION PAPER

REGULATORY FRAMEWORK FOR THE ELECTRIC POWER INDUSTRY

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REGULATORY FRAMEWORK

for

THE ELECTRIC POWER INDUSTRY

Alberta Department of Energy
April 15, 1992

REGULATORY FRAMEWORK FOR THE ELECTRIC POWER INDUSTRY

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Preface

This paper is the result of discussions by the Regulatory Review Task Force. Representatives were from the following organizations:

AEC Forest Products
Alberta Association of Municipal Districts and Counties
Alberta Federation of REAs Limited
Alberta Power Limited
Alberta Transportation and Utilities
City of Calgary Electrical System
City of Lethbridge
City of Medicine Hat
City of Red Deer
Cominco Fertilizers
Edmonton Power
Industrial Power Consumers Association of Alberta
Procter & Gamble
Small Power Producers Association of Alberta
The Municipal Intervenors
TransAlta Utilities Corporation

Members of the Energy Resources Conservation Board and the Public Utilities Board participated as observers.

The options and recommendations in this paper do not necessarily reflect the opinions of the organizations represented by members of the task force nor do they necessarily represent government policy.

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ALBERTA DEPARTMENT OF ENERGY
April 15, 1992

REGULATORY FRAMEWORK FOR THE ELECTRIC POWER INDUSTRY

EXECUTIVE SUMMARY

Background

The Alberta Department of Energy initiated a review of the current approach to regulation of electricity in response to suggestions and comments from the private utilities, municipal utilities and industrial consumers on aspects of electric utility planning and regulation in Alberta. These comments questioned the past effectiveness of the current regulatory process and suggested the need for a review of it. In addition, a review is warranted in light of changes in the environment in which the utilities are operating to determine whether changes would be appropriate to ensure an effective process in the future.

A task force comprised of representatives of investor-owned and municipal utilities, industrial consumers, Rural Electrification Associations (REAs), municipalities and small power producers is assisting the review. The task force identified a number of possible deficiencies in the current regulatory approach and possible options to address these deficiencies. The issues fall into three areas each concerning new facility additions within the current structure. The areas are the planning process, relation of plant ownership and contracts to the Electric Energy Marketing Act (EEMA), and mandates of the Energy Resources Conservation Board (ERCB) and the Public Utilities Board (PUB). The task force also identified potential changes to the approach to regulation and industry structure in light of changes and experience in other jurisdictions.

Planning Process

The responsibilities of the Boards and utilities for planning are not sufficiently articulated or necessarily consistent. The ERCB and PUB review the need for facilities in terms of provincial requirements. The utilities primarily plan facilities for their specific service areas within a plan for the total Alberta Interconnected System (AIS). There is no consensus on whether utilities are intended to propose facilities to supply the total AIS or to meet the forecast requirements of their service areas.

Options:

1. Each utility would be responsible for planning for the requirements of its own service area.
2. Coordination of planning by individual utilities would take place through the Electric Utility Planning Council to meet the requirements of all service areas but management of programs and proposals to contract for power or build new facilities would be separate.
3. Planning would be through a single entity for the total AIS such as a joint venture corporation formed by the major utilities distributing electricity. Ownership of new facilities and supply contracts with independent power producers could be divided among the utilities based on the total incremental load growth in each service area.

Formal stakeholder input at earlier stages of the planning process may be more effective than intervention primarily at ERCB hearings for facility applications.

Options:

1. Stakeholder involvement in load forecasting and planning would be confined to intervention in the ERCB facility hearings.
2. Stakeholders would be involved in ongoing technical committee meetings in an attempt to reconcile different views. Stakeholders would still intervene at ERCB hearings on those issues that could not be resolved in the technical committees.
3. Integrated resource planning hearings would be held at regular intervals (eg. three years) by the ERCB to determine an official load forecast range and a resource development and conservation plan.

It is recommended that the utilities and the ERCB involve stakeholders in the load forecasting and planning process through technical committees and determine the need for integrated resource planning hearings in light of the experience with the technical committees.

Plant Ownership, Contracts and EEMA

EEMA ensures that the costs of approved generation and transmission facilities are recovered from consumers of all three utilities (Alberta Power Limited, TransAlta Utilities and Edmonton Power). Due to this cost averaging, EEMA removes the need for explicit contracts between the owner of new plant and the distributing utility facing growth in its load. As a result, EEMA has become the implicit market for wholesale electricity.

Some stakeholders view this as inconsistent with the obligation to serve and with planning responsibility of each utility for its individual service area. Others view it as a necessary complement to one-system planning for the total AIS.

Options:

1. EEMA would remain the implicit market for generation facilities.
2. Distributing utilities would control facility additions by linking new facilities to incremental service area requirements by ownership or contract.

Mandates of the ERCB and PUB

Under the current regulatory process, decisions by the Boards regarding new facilities are separated in time as well as jurisdiction. There is potential inconsistency in the Boards' criteria in determining the need for additions to capacity, the choice among alternatives, the allocation between consumers and utility owners of new plant timing costs arising from demand uncertainty, and the timing of cost recovery. Alternatives were identified to allow for the option of dealing with issues under the PUB mandate at the time of plant approval by the ERCB and during plant construction.

Options:

1. PUB would hold a hearing to deal with potential conflicts between criteria affecting new plant at the time of ERCB approval.
2. A joint ERCB-PUB hearing would reconcile any differences between the ERCB's plant-approval criteria and the PUB's cost-recovery criteria.
3. A single board would deal with both the facility additions and rate regulation issues now split between the ERCB and PUB.

Approach to Regulation, Industry Structure and Performance

Beyond modifications to improve the current regulatory approach to new facility additions, changes to the traditional regulatory approach and industry structure are also under consideration. The Department of Energy is seeking formal comments on the following:

- The potential benefits to consumers of greater use of incentive regulation for utilities. (The current regulatory approach provides a limited range of incentives for improved performance.)
- The potential for improving the performance of the industry through competition in providing new supply and conservation options.
- Whether the current structure of vertically integrated utilities with exclusive distribution service areas provides the best framework for industry performance.

Next Steps

The Department of Energy is seeking formal comment on these issues and any other related issues interested parties think should be addressed. Comments will be considered along with the Department's analysis in preparing revised recommendations for further public comment.

Final recommendations will be integrated with any recommendations from the EEMA Review Panel appointed by the Minister of Energy. The Panel is reviewing the initial objectives of EEMA and determining if the current EEMA mechanism is appropriate for the future.

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REGULATORY FRAMEWORK FOR THE ELECTRIC POWER INDUSTRY

I. INTRODUCTION

Purpose of the Review

The basic objective of electricity regulation is the supply of safe and reliable electricity in an environmentally responsible manner at lowest cost, where such costs are recovered from consumers in a fair and equitable manner. In other words, regulation deals with broadly defined performance of the electric power industry. It can be seen as a proxy for competitive market forces to protect the interests of consumers. With a monopoly of electricity generation, transmission and distribution, the regulation system must encourage the utility to make investment, production and pricing decisions analogous to those of a competitive industry in equilibrium.[1] The result is prices that just cover costs, including a fair return to investors.

In 1989, and again following the transfer of responsibility for electricity policy to the Minister of Energy in January 1990, the government received suggestions and comments from the private utilities, municipal utilities and industrial consumers on electric utility planning and regulation in Alberta. The comments questioned the effectiveness of the current regulatory process. Building on work begun while electricity policy was managed by Transportation and Utilities, the Department of Energy initiated a review to determine whether changes could improve the effectiveness of regulation. Assisting is a task force of representatives of the investor-owned and municipal utilities, industrial consumers, Rural Electrification Associations (REAs), municipalities and small power producers, with regulators as observers. In meetings in 1991, the task force identified key issues and relevant options. These are summarized here with some preliminary recommendations.[2]

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[1] Prices in a competitive market go through cycles as the supply-demand balance changes. In equilibrium or on average, prices have to cover costs including a normal return on investment in order to sustain supply.

[2] The changes considered and proposed for new facilities would apply only to facilities not yet approved by the ERCB. Those under construction and not yet in rate base would be treated the same as facilities now in rate base.

The Department is seeking formal comment on these and related issues that interested parties believe should be addressed. The Department will use the comments and its analysis to prepare revised recommendations for further public comment. These will be integrated with any recommendations from the EEMA Review Panel which is conducting a review of the initial objectives and implementation of regulations under the Electric Energy Marketing Act.

Overview of the Issues

The issues identified by the Regulatory Review Task Force are divided into two broad categories: those related to new facility additions within current regulation and structure of the industry; and those related to improved industry performance through changes in industry structure and regulation approach.

New Facility Additions Within the Current Structure

There are three fundamental questions concerning new facility additions that the regulatory process has to address:

- When are additional generation plants and transmission facilities likely to be needed and when should commitments be made to new facilities?

- When, and how much, should customers pay for such facilities?

- How can the regulatory process best assure that decisions are in consumers' interests, taking into account the need to balance short- and long-term interests?[3]

Consumers must pay for the full, justifiable cost of the facilities required to provide electricity service, including a fair return for those making the investment.

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[3] The costs of different supply and conservation options clearly include environmental costs and benefits, however, this paper does not address the adequacy of the current regulatory process in taking these into account.

Due to the uncertainty of the future level of demand for electricity and the time required to plan and construct generating facilities, it is unlikely that large new plants can be ready exactly as needed. To ensure that decisions are in consumers' best interests, the regulatory framework, process and Board decisions must assign responsibilities and explicitly or implicitly establish a system of risks and rewards that is efficient from the consumers' point of view.[4]

The Task Force identified three areas for possible improvement in the current regulatory approach which pertain to three fundamental questions respecting new facilities:

- **The Planning Process:** The process of forecasting load growth, identifying supply and DSM options, and planning additions of such options.

- **Plant Ownership, Contracts and EEMA:** The effect of the EEMA mechanism on the relationship between service territory load requirements and ownership of generation and transmission facilities or contracts for capacity.

- **Mandates of the ERCB and PUB:** The appropriateness of the ERCB and PUB mandates as the mandates determine the roles and criteria used by the Boards in determining the need for capacity additions, the choice among alternatives, the allocation between consumers and utility owners of new plant timing costs arising from demand uncertainty, and in determining the timing of cost recovery.

Changes in Regulatory Approach and Industry Structure

Changes should be considered to the regulatory approach and industry structure based on experiences and changes in other jurisdictions. This should consider their potential relevance in improving electric power industry performance in Alberta.

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[4] See appendix A for a discussion of the allocation of risk of future demand uncertainty.

- **Competitive Bidding for New Supply:**[5] The potential for improving industry performance through competition in providing new supply.

- **Incentive Regulation:** The potential of greater use of incentive regulation for improvements in performance and benefits to consumers.

- **Structure of the Industry:** The suitability of the current structure to deal with future planning and performance challenges.

II. BACKGROUND

Industry Structure, Planning and Regulation

The combination of elements of the Alberta Interconnected System (AIS) is unusual in North America and unique in Canada:

- Three large, separate, vertically integrated utilities (TransAlta Utilities (TAU), Alberta Power Limited (APL) and Edmonton Power (EP)), with generation and transmission facilities that are operationally integrated and for which costs are pooled; plus Medicine Hat's small integrated utility treated in operational and cost terms as an isolated system.

- Three large and several small municipally-owned distribution systems that purchase power on a wholesale basis from TAU. There are also many Rural Electrification Associations (REAs) that own distribution systems and purchase power from TAU and APL.

- Regulation of facility additions that treats the AIS as an integrated system, while load forecasting is done jointly through the Electric Utility Planning Council (EUPC) but facility planning is done individually and to some extent competitively by the utilities.

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[5] Competitive bidding could also be considered for conservation options.

The complexity of planning, facility approval, cost equalization and rate regulation may give the impression of a patchwork structure not fully aligned with the integrated concept of the AIS. Regulation of cost of service and rates[6] treats utilities as separate but connected by the EEMA transfers. Yet TAU, APL and EP are highly integrated through ERCB regulation of facility additions which are approved to provide service province-wide, and the centralized operation of the generation and transmission systems. These complex regulatory policies reflect an attempt to deal with integration on the AIS and utility independence concurrently.

The Current Regulatory Process

There is general agreement among Task Force members on a description of the current regulatory approach to answering the three fundamental questions concerning new facilities.

The current approach can be summarized as follows. The utilities, on an individual basis, take initiative in deciding when plants are needed, in proposing specific plants and demonstrating need. The ERCB responds, deciding when plants are needed and which should be built if competing applications are filed.[7] When ERCB-approved plants are complete, the PUB decides when consumers should start paying for new facilities and how the costs of demand uncertainty (i.e. construction of a plant being started and completed before it is needed) should be shared between consumers and utility shareholders. Assurance that decisions regarding new facilities balance the interests of consumers and utility owners is provided by the hearing processes of the ERCB and the PUB, and by putting utilities at risk for potentially paying part of the costs of future demand uncertainty.[8]

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[6] Edmonton Power's generation and transmission costs pooled through EEMA are regulated by the PUB. Their consumer rates are regulated by City Council.

[7] The ERCB decides what to approve but requires the authorization by the Lieutenant Governor in Council to issue the approval.

[8] Hypothetically, the utilities are also at risk of: being penalized for not having sufficient capacity available and thereby reducing the reliability of service to customers; or sharing with customers the cost of having to resort to higher cost, shorter lead-time facilities or purchased power to meet demand. Since there have been no cases in which major new facilities were not available in time, the response of the PUB to such a situation has not been tested.

In the debate following the Genesee 2 decision, the utilities argued that, prior to that decision, they believed their risks centred only on the prudence of construction cost management of new facilities. The risk around the load forecast was believed to be with the consumer. Utilities believed they had a prudence requirement with the need to recognize changes to load forecasts as early as possible while new facilities were under construction. Consumers on the other hand argued that utility rates of return compensated them for the cost of demand uncertainty imposed on them.

In more detail, the roles and elements of the current process are:

Utilities

The utilities take the initiative in deciding what plants should be built, and when.

- The utilities forecast load, plan facilities and are accountable

  - to the ERCB to demonstrate publicly that their forecasts are competent and reasonable, and that plant proposals represent an orderly economic development of resources and are in the public interest; and

  - to the PUB to demonstrate, upon commissioning of the new plant, that it is used or required to be used,[9] that costs are not imprudent, and that the proposed cost of service is reasonable.

- The Electric Utility Planning Council (EUPC) is a utility forum for preparing load forecasts, with limited discussion of facility additions. The EUPC has no authority to determine which facilities should be proposed to the ERCB because such decisions involve individual utility business considerations. The ERCB's total AIS approach to reviewing proposed facilities treats the province as one single market. Given that approach, the cost-sharing under EEMA has the effect of offering a common market for new generation proposals and hence the potential for competing proposals from utilities. As a result, while generic information is exchanged, little, if any information about specific generation options is shared within the EUPC.

- Some consumer groups are discussing and collaborating informally with some utilities on resource planning.

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[9] The "used or required to be used" test has been interpreted by the PUB and confirmed by the Alberta Court of Appeal to be both conjunctive and disjunctive, depending on the circumstances.

- The utilities propose new plants on their own initiative. The current regulatory treatment of new facilities relies on utility incentives and risk to promote decisions in the interest of consumers. For new facilities, the incentives for efficiency and the risks to utilities include:

  - the desire to provide high quality service to customers;

  - the incentive to identify and propose to the ERCB the lowest-cost plant to be added as the next increment of capacity;

  - risks associated with the PUB finding imprudent construction costs or response to changes in load forecasts; and,

  - the incentive to avoid over-estimating load in light of the risk of delay in adding into rate base any new plant that is not used or required to be used at the time of completion.[10]

ERCB

Responding to the initiative of utilities and independent power producers (IPPs), the ERCB decides when facilities are required to meet forecast AIS needs and, when there are competing applications, which are to be added. The ERCB criteria are lowest lifetime cost of power and other public interest criteria related to the orderly economic development of resources in the province.

- On the basis of EUPC or utility forecasts, utilities identify a need for new plant and propose new facilities to the ERCB. In principle, IPP sponsors can also propose a new plant.

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10 When proposing a new plant utilities have to consider the possibility of priority being given to conservation or to other capacity options, such as independent power facilities or the extension of units scheduled for retirement, subsequent to the approval of long lead time plants.

- The ERCB is the final arbiter concerning the load forecast. The Board relies on information provided through the hearing process, supplemented by its expertise, to evaluate the utilities' forecasts that underlie applications for facilities to meet forecast requirements.

- The ERCB subjects applications to public scrutiny through its hearing process. It determines the need for new capacity based on information provided in hearings and its load forecast. It selects from proposed facilities the configuration and timing of plant additions that it believes will yield the lowest lifetime cost of power and satisfy other public interest criteria.[11]

- The ERCB's role is not totally passive: while the ERCB does not have authority to order utilities to invest in a plant, it can initiate a show-cause hearing if it believes utilities are not proposing needed plants or if they failed to revise originally-approved construction schedules because of changes in demand during construction.

PUB

The PUB decides when, and how much of, the cost of new facilities should be recovered from consumers.

- Upon commissioning of new plant, sponsoring utilities apply to the PUB to include the plant in rate base and/or recover costs through the EEMA mechanism.

- As prescribed by statute, the PUB applies a 'used or required to be used' test for new facilities to be included in the rate base. If the plant is not required to be used over the test period, the PUB can determine the appropriate timing of cost recovery, and set the rate of return to the utility in a way that shares the costs of demand uncertainty between the utility and customers.

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[11] The ERCB comparison of different alternatives over their lifetimes involves discounting uncertain (forecast) capital, fuel and other operating costs. The discount rate may be the utility cost of capital, a social discount rate or some other appropriate rate. The ERCB may look at the difference among alternatives on a year by year basis as well, but the Board does not usually consider directly the impact of alternatives on customer rates. Given the possibility of greenhouse gas emission standards in the future, the environmental aspect of alternatives may become more significant.

EEMA

Under the Electric Energy Marketing Act, PUB-approved costs of generation and transmission are averaged and recovered from all consumers served by TAU, TAU wholesale customers, APL and EP.

- EEMA equalizes the costs of generation and transmission facilities across customers of TAU, APL and EP in a way intended to leave shareholders indifferent and unaffected by short-term fluctuations in load and cost.

- It also provides the de facto wholesale market for the output of generation facilities approved by the ERCB and the PUB. EEMA serves as purchaser from the generators and seller to the distribution areas requiring additional capacity. This eliminates the need for explicit contracts between the owner of new plant and the distributing utility facing growth in its load. However, the 'obligation to serve', or responsibility to ensure requirements of distribution markets are met by the generation capacity, remains with the utilities for their own service areas.

- In spreading the cost of capacity among all consumers in the AIS,[12] EEMA dilutes the effect of a utility's new facilities' cost on its distribution customers.

- It also minimizes the significance of business arrangements that enable efficient inter-utility cooperation and shares equally the benefits of that cooperation in various areas: least cost dispatch; the maintenance of reserve capacity for the AIS; out-of-province sales of power; and building of generation units which may be larger than needed for the immediate requirements of a utility's own customers.[13]

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12 Medicine Hat's requirements and generation facilities are part of the AIS, but the city is not covered by EEMA.

13 Sharing of reserve and cooperation that allows utilities to build units that are larger than needed for their own immediate requirements should not be attributed exclusively to EEMA. These occur in other power pools without cost pooling and occurred in Alberta prior to EEMA.

Independent Power Producers (IPPs)

- In principle, IPPs' projects are treated in the same manner as proposed new utility-owned plants. It is not clear whether such projects would be approved on the basis of need and an "implicit power contract" with EEMA. Because IPPs and financial backers would not likely proceed on the strength of an implicit power contract under EEMA, IPPs would probably require a host utility to provide the power contract.

Power Exchanges with BC and Saskatchewan

- In the past, a provincial intertie was included in rate base when it was an economic alternative and when needed to ensure electricity supply to Alberta consumers. For example, the intertie with B.C. is in rate base since it provides 400 MW of reserve capacity for the Alberta system, effectively displacing the need for generation capacity.

- However, a provincial intertie that was constructed and commissioned, but not required to supply electricity to Alberta consumers, was excluded from rate base until need for the intertie is demonstrated. The intertie with Saskatchewan, commissioned in 1989, was not allowed into rate base as it was not projected to be required to serve Alberta consumers until 1995. The Saskatchewan intertie is currently being used primarily to serve export customers. The carrying charges of the intertie will be recovered from the Saskatchewan Power Corporation until 1995.

Demand Side Management

- Approval for expenditures on conservation and other forms of demand-side management (DSM) falls under the jurisdiction of the PUB. The ERCB takes DSM into account as the final arbiter concerning the load forecast for Alberta. However, the ERCB does not appear to have a role in implementing DSM measures.

Broad Issues Facing the Industry in Alberta

The basic issue this review is addressing is whether there are aspects of the current approach to regulation or industry structure that should be changed to improve planning or the cost effectiveness of the electrical system, identifying which changes require legislative amendments and which changes can and should be addressed by the Boards within the regulatory process.

The next two sections identify issues and options[14] for improving the regulatory process. As outlined in the introduction, issues are in two broad groups: those dealing with new facility additions within the current industry structure and approach to regulation; and those dealing with potential improvements in industry performance through changes to industry structure or regulation approach.

III. NEW FACILITY ADDITIONS WITHIN THE CURRENT INDUSTRY STRUCTURE

Goals and Deficiencies of the Current Regulatory Treatment of New Facilities

The goals of the current regulatory treatment of new facilities include the following:

Orderly and economic development of resources.

Efficiency benefits of timing and designing plants to meet total AIS requirements - economies of scale, location, mix of types of generation.

Choice among potential generation, transmission (and DSM) alternatives should pursue a balance of both short- and long-term interests of consumers by responding to changing circumstances in light of evidence put forward in hearings.

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[14] Based on a broad consensus during Task Force discussions, there is one recommendation in the next session and two in the Appendix.

Appropriate degree of supply reliability, recognizing the cost of differing degrees of reliability.

Effective allocation of responsibilities and a cost-effective system of risks and rewards to utilities to get optimal timing and type of new facilities.

Timing of recovery of costs of new facilities to represent equitable allocation among consumers over time and avoidance of rate instability.

Task Force discussions suggest that there may be a number of deficiencies in the current approach:

The responsibilities of Boards and utilities for planning are not sufficiently articulated or necessarily consistent. The planning responsibility of utilities is not structurally matched to the regulatory approach (by ERCB) -- the ERCB looks at facilities in terms of total AIS, whereas facility planning is done by individual utilities primarily for their service areas. There is no consensus on whether utilities are intended to plan and propose competing facilities to supply the total AIS or whether they are intended to propose facilities to meet the forecast requirements of their respective service areas, within a plan for the total AIS.

To the extent that utilities are intended to compete to provide facilities to meet forecast requirements of their own (and other) service areas, the method of addressing the issue of self dealing has not been adequately specified.

If utilities are to plan for their own service areas, the responsibility for planning is not matched to the ERCB and PUB review of facilities on the basis of total AIS requirements -- utilities adding new facilities are held responsible for the variations in load for the total AIS and for additional generation facilities added after approval of their plant (eg. small power, cogeneration).

The implicit market for capacity aspect of EEMA is inconsistent with responsibility by service area.

There is a potential inconsistency of ERCB and PUB criteria -- 'lowest lifetime cost' and 'other public interest' vs 'used or required to be used in the test year'.

There is no clear process for integration of conservation and other DSM measures with facility planning due to the separation of responsibility for approval of facilities by the ERCB and DSM expenditures by the PUB.

Restricting stakeholder contribution during the planning process to intervention at ERCB hearings for facility applications may be less effective than allowing stakeholder input and commitment during earlier stages.

A. The Planning Process

In a regulated industry such as electric power, the government through its legislation, policy and regulatory agencies, is and should be responsible for ensuring that appropriate planning takes place.

The question for this review is whether any changes in legislation and/or roles of the ERCB and PUB would improve the effectiveness of planning. The approach used to address the question is to ask explicitly what would best serve consumers over time and implicitly whether changes should be made to the current method. The question of whether responsibility for ensuring that utilities plan appropriately should remain with the ERCB is addressed in the section on Board mandates.

What is the structure of planning and regulatory process for identifying supply and DSM options, forecasting load growth and planning additions of capacity to the AIS that will best serve the interests of consumers in Alberta over time? What are the opportunities and responsibilities of all parties in the planning process?

Issue: Method of Planning - Separate by Service Area, Coordinated, Single Entity

While the government, through the ERCB, has responsibility for ensuring that proper load forecasting and facility planning occurs in a timely fashion, the actual planning is carried out by the utilities both as distributors and generators of power.

In its oversight of the planning process, the government, through the regulatory boards, must consider the merits of degrees of coordination of planning for the AIS. Would consumers be better served by autonomous planning by individual utility, coordination of planning through the EUPC, or planning by a single entity for the total AIS requirements? How are alternatives related to incentives for good planning and regulatory treatment of new facilities?

Options:

1. Individual utility responsibility for planning for its service area:

   Each utility would be responsible for forecasting its service area load, planning for DSM and the supply requirements of its service area through a combination of contracts with IPPs or other utilities, and building new facilities. In seeking regulatory approval of plans, each utility would be required to demonstrate that it had sought cooperation with other utilities.

2. Coordination of planning by individual utilities through the EUPC for total AIS needs; separate facility proposals:

   The utilities as distributors would coordinate their planning for the future needs of their joint service areas through the EUPC. They would coordinate, but manage separately, their Demand Side Management programs, IPP supply contracts and their proposals to build new facilities.

3. Planning by a single entity for the total AIS:

   The major utilities could form a joint venture corporation responsible for forecasting and planning. The joint venture would prepare plans for a combination of Demand Side Management programs, supply contracts with IPPs or utilities outside Alberta, and new facilities and propose them to the ERCB. Ownership of new facilities and IPP supply contracts could be divided based on each utility's service territory share of total incremental load.

Issue: Form of Stakeholder Involvement

What regulatory process and form of stakeholder involvement in load forecasting and planning, whether by individual utility or by a single entity for the AIS, would result in the most effective planning? How do the different forms of involvement affect the quality of planning? What is the relationship between stakeholder involvement and utility responsibility and incentives?

The options identified reflect two aspects of the issue:

- Whether stakeholders should be involved in forecasting and planning outside of the hearings dealing with facility applications; and if so,

- Whether the form of involvement would be through ongoing technical committees of utilities and other stakeholders or integrated resource planning hearings.

Options:

1. Utilities present their load forecast and planning proposal to the ERCB as part of their applications for new facilities. Stakeholder involvement in load forecasting and planning would be confined to intervention in the ERCB facility hearings.

2. The utilities involve stakeholders in ongoing technical committee meetings in an attempt to reconcile different views and decide on the forecast or forecast range they use for planning purposes and the choice among options to be proposed at ERCB hearings. Stakeholders would still intervene at hearings on those issues that could not be resolved in the technical committees.

3. The ERCB would hold integrated resource planning hearings at regular intervals (eg. three years) to determine an official load forecast range and resource development and conservation plan. Utilities would be required to demonstrate their facility applications are in accordance with the integrated resource plan, or justify a departure from it.

Recommendation:

The utilities and the ERCB involve stakeholders in the load forecasting and planning process through technical committees and determine the need for integrated resource planning hearings in light of the experience with the technical committees.

B. Plant Ownership, Contracts and EEMA

What relationship between service territory load requirements and ownership of (or contracts for) generation and transmission facilities will promote the most effective planning and selection of the optimal facilities to be added?

Traditionally, utilities did the planning, and contracted for or built the facilities to meet the requirements of their service territory. EEMA not only pools generation and transmission costs; it represents an implicit market for capacity approved by the ERCB and PUB to meet total AIS needs. Thus EEMA has overridden the traditional ownership or contractual link between facilities and service territories.

Issue: Control Over When and What Gets Added

Would individual utility control over new generation and transmission facilities required to meet the needs of their service territories contribute to better planning and lower costs of dealing with future demand uncertainty? Would such control be compatible with ERCB criteria for approving new facilities for total AIS requirements?

Options:

1. Status quo: plants chosen in regulatory process to serve total AIS requirements. Even in the absence of contracts between the plant owner and the distribution area requiring additional capacity, the costs of approved facilities are recovered from customers of all three utilities through the EEMA mechanism.

2. Distributing utility control over facility additions through a linking of new facilities to incremental distribution service territory requirements by ownership or contract. An IPP proposal would have to be linked by contract to a utility requiring the capacity. A utility proposing new facilities would have to demonstrate that all relevant options for new capacity had been considered and that it had contracts for any capacity not required for its own service territory over the relevant planning period.[15]

C. Mandates of the ERCB and PUB

Do the respective mandates of the ERCB and PUB lead to appropriate processes, roles and criteria of the Boards in reviewing supply and conservation options and the timing of new plant additions?

There are two separate regulatory questions connected with new facilities:

- Facility planning: the determination of what plants should be built when, which is under ERCB jurisdiction; and

- Revenue requirements and rates: approval of costs, timing of cost recovery and rate design which is under PUB jurisdiction.

When the PUB delayed the recovery of costs of the Genesee and Sheerness generation plants and the SPC intertie and Keephills/Ellerslie transmission lines, a debate over the relationship between these two areas of jurisdiction began.

Under current regulation of new facilities, decisions are separated in time as well as jurisdiction. The determination of the allocation between consumers and utility owners of the costs of completing new generation plants before they are needed is decided by the PUB at the time of commissioning of new plant, on the basis of hearing evidence many years after the initial and subsequent ERCB approvals of plant construction.[16]

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15 For this option to provide significant incentives for better planning, the approach to cost sharing of excess capacity through EEMA and the sharing of costs between consumers and utility shareholders might have to be modified.

16 See Appendix A for a discussion of the approach to allocating the risk of demand uncertainty.

Issue: Board Mandates & Timing of Consideration of New Plant Issues

Do the mandates of the Boards and the division of responsibilities between them, allow the Boards to set appropriate and consistent criteria for plant approval, timing of cost recovery and allocation of risk between utilities and consumers, that are likely to be in the interests of consumers over time?

Could the clarity of criteria, effectiveness and efficiency of regulatory approval of new facilities be improved by different mandates and responsibilities of the ERCB and PUB?

Options:

Three alternatives were identified to allow for the option of dealing with issues under the PUB mandate, such as the allocation of the risk of demand uncertainty, at the time of plant approval by the ERCB:[17]

1. PUB would hold a hearing to deal with risk allocation of new plant and potential conflicts between criteria affecting new plant at the time of ERCB approval.

2. A joint ERCB-PUB hearing would reconcile any differences between the ERCB's plant approval criteria and the PUB's cost recovery criteria and determine risk allocation of new plant at the time of approval of plant by the ERCB. The joint approach could be set up as an Electric Utility Board, analogous to the Gas Utility Board, that deals with issues falling under joint ERCB-PUB jurisdiction.

3. A single board could deal with both facility additions and rate regulation issues, now split between the ERCB and PUB. Having a single board deal with all aspects of regulation of electricity would appear to allow for clearer criteria and simpler coordination of plant approval and rate-setting decisions.[18]

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17 In addition to coordinating the current work of the two Boards under the three options, amendments of the Hydro and Electric Energy Act and the Public Utilities Board Act might be necessary to ensure that new facilities are treated in a legislatively consistent manner.

18 The PUB could simply take over from the ERCB both the regulatory responsibility and the staff for planning and approval of facility additions.

Relationship Among the Planning, Control and Board Mandate Issues and Options

In summary, the issues and options are as follows:

A1. Planning

1. Separate planning by TAU, APL, EP.

2. Coordinated need planning, separate facility proposals.

3. Planning by a single entity for the total AIS.

A2. Stakeholder Involvement in Planning

1. Stakeholders involved only through intervention in facility application hearings.

2. Utilities consult stakeholders throughout the planning process through technical committees. Stakeholders intervene in hearings on issues not resolved in technical committees.

3. Stakeholders involved through intervention at regular integrated resource planning hearings.

B. Control by the Distributing Utility of When and What Facilities Get Added

1. Status quo.

2. Distributing utility control, subject to regulation, through contracts that would be required for facility approval.

C. Board Mandates and Responsibilities

1. PUB mandate to examine timing issues at time of plant approval.

2. Joint ERCB-PUB examination of timing issues at the time of plant approval.

3. PUB takeover of plant approval responsibility from ERCB.

The different options for the approach to planning, stakeholder involvement, control over facility additions and Board mandates in approving new facilities, are interrelated.

Control by individual utility (B-2) goes together with planning by individual utility (A1-1), or perhaps also with coordinated need planning with separate facility proposals (A1-2). The combination of those two might make integrated resource planning hearings (A2-3) more desirable or necessary and affect the relative merits of choices of mandates of Boards under C, perhaps favouring the single board approach (C-3).

The single entity approach to planning and control of facility additions (A1-2) may go well with the technical committee approach to stakeholder involvement (A2-2) and be consistent with the current division of responsibilities between the ERCB and PUB.

These combinations can be summarized as follows:

Control by Utility	Single Entity Approach
B-2 Distributing utility control of facility additions for its service area requirements through ownership or contract.	B-1 Facility additions approved for total AIS.
A1-1 Planning by individual utility or A1-2 Coordinated need planning with separate facility proposals.	A1-3 Planning by a single entity for the total AIS.
A2-3 Integrated resource planning hearings.	A2-2 Technical committee approach to stakeholder involvement.
C-3 Single Board regulating facility additions, cost of service and rates.	C-1/ C-2 Current division of responsibilities between the ERCB and PUB.

In addition to the relationship of issues raised here, the various combinations of options are related to alternatives regarding the approach to regulation and the structure of the industry.

IV. THE APPROACH TO REGULATION, INDUSTRY STRUCTURE AND PERFORMANCE

The previous section addressed ways of improving the current regulatory approach within the current structure of the industry. This section raises the question of whether changes in the approach to regulation or the structure of the industry could lead to improved performance of the industry. While the issues and options in this area have not been discussed in detail by the Task Force, the Department is seeking comment on the wider issues of the approach to regulation and industry structure to help direct further work by the Task Force. Specifically, we would like comments on whether or not utility costs could be reduced through incentive regulation and new facilities costs could be reduced through competitive bidding for new plants.

A. Incentive Regulation

The current regulatory approach provides a very limited range of incentives for improved performance. Apart from the risk of bearing a share of the costs of demand uncertainty, the utilities have two financial incentives for good performance:

- Avoidance of disallowance of costs due to a finding of imprudence.

- Fixed rates allow for higher profits between rate cases if the utility reduces costs below the level assumed for setting rates. However, this incentive is tied to the effect on profits due to variations in load with weather and economic activity over which the utility has little or no control. Fixed rates also provide a disincentive to promote conservation between rate cases.

Regulatory boards in other jurisdictions have adopted a wider range of performance incentives, some of which may be appropriate in Alberta.

The objective of introducing additional incentives would be to encourage utilities to improve control of costs, promote cost-efficient conservation and improve efficiency by providing additional links of utility returns to performance. The incentives should not replace

prudence review and regulatory lag, though the latter might be made more effective by reducing the effect of weather and economic cycles on utility returns.

To be effective, the incentives should be tied to performance over which the utility has some control and recognize the many dimensions of utility performance. To be credible, the level of incentives (both rewards and penalties) must be limited to acceptable levels. The utility (and consumers) must believe that rewards and penalties will not be reversed after the fact. To be fair and acceptable, the utility must expect to earn its normal return for normal performance and the incentives must produce improved results.

B. Competitive Bidding for New Supply Options

Some jurisdictions have adopted a competitive process to determine which facilities are added, or DSM options selected, to meet or reduce load requirements to improve cost performance. Competitive bidding procedures were introduced in response to a number of factors, including: cost overruns; excess capacity; the utilities' weakened financial condition; and, technical changes that have questioned the need for vertically integrated utilities and to solve the problem of determining utility avoided cost as a basis for IPP contracts. The question is whether such procedures would yield better cost performance for future power supply options in Alberta.

Barriers to IPPs

In order to implement a bidding process there has to be no barriers to IPPs in the regulatory process. The current ERCB process does not exclude IPPs from applying to supply Alberta's electrical requirements. However, in the past, the ERCB has responded to applications to build new plants as they are submitted. Since they have the obligation to meet the customers' needs, the utilities would take the initiative in deciding when and what plants should be built since they have the obligation to meet customers' electricity requirements. This may have precluded consideration of alternative sources that were not involved in the planning process and/or had shorter lead times. In the 1970s and early 1980s, the utilities' coal plants were the alternatives with the lowest expected cost. Since then, changes in technology, fuel cost and environmental standards have improved the relative cost performance of gas-fired generation and other alternatives.

In the future, the ERCB may require more comprehensive testing of alternative options before approving an application. Alternatively, a process to identify a block of capacity requirements that need to be met could be implemented. This would ensure all potential developers are aware of the opportunity. Combining this with increased involvement of stakeholders in the planning process may address any barriers to potential developers.

DSM Initiatives

Demand-side management initiatives have different characteristics than supply options and may require different regulatory treatment and/or different bidding procedures than utility and IPP supply options. An appropriate method to include conservation measures in the planning process is needed.

Benefit of Competitive Bidding

The key element of a competitive bidding process is that it provides a comprehensive evaluation process for comparing different applications at the planning and facility approval stage and different DSM initiatives at the load forecasting and facility planning stages. In the past, for supply options, the utilities' experience and information base may have given them an advantage over IPPs in proving that their applications were the best options. For DSM options, utilities had no incentive, and likely faced a disincentive, to pursue conservation measures. A more comprehensive evaluation process could benefit consumers by ensuring the least-cost supply and efficient conservation measures are pursued. It would also provide additional incentive to the utilities to pursue the least-cost alternative for meeting future load requirements.

Would there be a benefit to implementing competitive bidding in Alberta?

Competitive bidding can be successful only if the potential exists for a competitive market with a sufficient number of proposals competing. One reason bidding is not undertaken in some jurisdictions in the U.S. is that the alternative sources to meet load requirements are not competitive with utilities.[19]

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[19] The Cogeneration Study currently being undertaken by the Alberta Department of Energy will provide some indication of the IPP potential in Alberta.

The evaluation procedures under competitive bidding would be complex to ensure a fair and competitive environment. Some factors that would have to be addressed:

- potential self-dealing if the host utility is included in the bidding process;
- potential transfer of risk from IPPs to the utilities - for example, most IPPs could not bear the risk of demand uncertainty;
- relative reliability and the flexibility in dispatching of various options; and,
- the costs of assuring the performance of IPPs, for example through penalties for non-attainment.

Due to this complexity, the administrative costs of competitive bidding may outweigh the benefits. Another consideration is that prerequisites to entering the bidding process, such as reliability or dispatchability, may reduce the number of participants and therefore the degree of competition in the bidding process.

Industry Structure

Does the current structure of vertically integrated utilities with exclusive distribution service areas provide the best framework for industry performance? What are the advantages and disadvantages of the current structure vis-a-vis alternatives such as a "modified British structure" under which:

- The generation and transmission operations of utilities would be separated from distribution. Consumers would continue to be served by their current distribution utility, whether private or municipal, which would retain responsibility for supply.
- The ownership of generation and transmission facilities would remain with generating utilities, but a new planning and wholesale marketing company would separate them from distribution operations. The marketing company or agency would be the purchaser of power from generators and the wholesale supplier to distribution utilities.

- Transmission facilities would be regulated as open access carriers of power for the marketing company to distribution utilities.

- The marketing company would assume the costs of all of the existing facilities under life-of-facility contracts with rates set by the PUB or modified under a new form of incentive regulation.

- The distribution utilities would in turn sign long-term contracts with the marketing company for power supply at its regulated cost of delivered power.

- When the need for new facilities is identified, the distribution companies would contract for additional power with the marketing company, which in turn would contract with a generating utility, independent power producer or cogenerator that could supply the most cost-effective power.

- If the marketing company were given a monopoly over power supply to distribution utilities, the cost equalization and integrated operation of the AIS would continue. The marketing company would do explicitly through contracts what EEMA now does through regulation.

- Alternatively, direct competition at the distribution level could be introduced for incremental new capacity by allowing distribution utilities to contract directly with generators for increases in their power needs, and arrange for wheeling under contract on the transmission system. That would maintain cost equalization only for existing facilities and could reduce benefits of coordinated operation.

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APPENDIX A: RISK-OF-DEMAND UNCERTAINTY

There are more, and less, efficient ways of allocating responsibilities and risks between utilities and consumers. Consumers bear the costs of the underlying risk in supplying electricity directly and indirectly because utilities receive a rate of return that reflects the degree of risk they assume. One element of how the regulatory process can best assure that decisions are in consumers' interest is: to what extent can utility performance be improved by assuming a greater share of the costs of uncertainty, how much must they be compensated for different types and degrees of risk, and what sharing of costs is in consumers' interests? The answer may affect elements of the regulatory process, such as the timing of PUB consideration of issues related to new facilities or the nature of regulatory oversight of the construction of new facilities.

Utilities have argued that the cost of capital will be higher, and the greater their exposure to the risk of demand uncertainty. If they are exposed to the risk of bearing significant costs of future demand uncertainty despite prudent decisions, they may not propose long lead-time plants, even though such plants may have lower lifetime costs than short lead-time plants. Consumers argue that the utilities are already compensated for the risk of the share of the costs-of-demand uncertainty imposed on them by the PUB. In any case, with greater potential costs of demand uncertainty due to slower load growth and possible costs of meeting uncertain future greenhouse gas emission standards, long lead-time coal plants may not be lower cost than shorter lead-time gas plants.

These issues have arisen primarily as a result of the manner in which the industry and regulatory system responded to the dramatic reduction in electric load growth below the levels expected and committed for capacity planning in the 1980s.

Issue: Approach to Allocating Risk-of-Demand Uncertainty

Should there be any change in the approach of determining who bears the risks of excess capacity when new generation facilities are built in advance of need: how the costs of that excess are allocated and the timing of recovery of costs of plants completed prior to being needed?

Risk allocation is reflected in PUB decisions on what investment (including AFUDC and PHFFU)[20] costs are to be recovered from customers, when they will be recovered, and what the allowed rate of return (and AFUDC and PHFFU rates) will be. Implicit in the Task Force discussion of the approach to allocating risk-of-timing errors[21] are three broad alternatives of what the outcome of the regulatory process might be.

- Regulatory approval would be given to a utility to build "the next plant", but the utility would be at risk of delay of cost recovery (in the extreme, indefinitely) beyond the originally approved commissioning date, reduction of its allowed rate of return or partial denial of AFUDC if the anticipated load growth failed to materialize by the time of plant completion. The costs imposed on the utility and consumers would depend on the balancing of consumer and utility owner interests by the PUB. (It is unlikely that consumers would find it cost-effective to compensate utilities for taking all the risk of demand uncertainty, i.e. not allow recovery of costs in excess of the minimum required to add a new plant, forcing the utility to absorb extra AFUDC and PHFFU costs for plants delayed and/or completed before they are needed.)

- At the same time, the regulatory process would deal with the selection of when and what facilities should be added and the timing of their inclusion in rate base. The utility could be found to be imprudent with regard to expenditures on the plant, but, assuming the utility commissioned a new plant on the date approved by the regulators, lack of need for the plant at the time of completion would not be evidence of imprudence.

  If the load forecast were revised downward after initial approval, regulators would presumably revise the approved commissioning date. As long as the plant were commissioned on the revised date, it would go into rate base at that time.

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20 Interest costs of: Allowance for Funds Utilized During Construction, and Plant Held For Future Use.

21 "Timing errors" are errors in hindsight. They are the outcome of timing decisions in the face of demand uncertainty at the time of initial approval of facilities.

- The third alternative differs from the second only in terms of the timing of recovery of costs. The initially approved commissioning date would be reviewed periodically during construction in light of changing circumstances. As long as the utility sought revision of the commissioning date as required by the changing circumstances, the utility would be assured of recovering the costs of the plant, including the prudent costs of adjusting to those changes, and the utility would receive its normal allowed rate of return. The question of the timing of recovery of costs would depend on the circumstances, but could include the options of delay in recovery of any costs until the plant is required, allowing partial or full construction work in progress (CWIP), and inclusion of the plant in rate base prior to its being required.

Options:

Three basic alternatives for the process of determining risk allocation were identified:

1. Status quo -- ERCB chooses which plant should be added; PUB determines allocation of costs-of-timing errors and the timing of recovery of costs at the time of plant completion.

2. Legislatively allocate to consumers all new plant costs of future demand uncertainty, except those resulting from demonstrated imprudence, based on the assumption that certainty of prudent cost recovery would result in the utility having a lower cost of capital than would otherwise be the case to the benefit of consumers.

3. Add to the regulatory process a PUB review of timing of new plant at the time of selection and during construction, with an option to determine the allocation of costs-of-timing error between consumers and utilities at the time of initial application for approval to construct the new plant or applications to revise the commissioning date.[22]

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[22] This approach has been described as allowing different regulatory rules for different circumstances, but making them clear prior to construction of facilities.

Recommendations:

1. The regulatory process dealing with new plant additions should allow for the determination of the allocation of risk-of-demand uncertainty between consumers and utilities at the time of initial approval to construct facilities.

   This procedure would allow flexibility in dealing with different types of plants and differing circumstances over time and a determination of what is appropriate in each case on the basis of evidence in a regulatory hearing.

2. The jurisdiction of the two boards should allow for appropriate oversight during plant construction.

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